Nebraska Public Power District

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July 22, 2011

Paul Hoornaert, P.E.
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Subject: NPPD Transmittal 282 - Comments on Sargent & Lundy's Revised Cost Estimate

Paul:

Attachments B and C to NPPD's Transmittal 282 contain questions from District personnel working on modeling the cost impacts of various potential MPCE scenarios for Gerald Gentleman Station (GGS) that may be required due to recently issued and potential new environmental regulations (See Attachment A). The District is requesting that appropriate S&L personnel provide responses to the questions contained in Attachments B and C to facilitate this analysis effort. Please have appropriate Sargent & Lundy personnel address as many of the comments as possible by August 3, 2011 if possible.

Please contact me at GGS 308-386-5312 or via e-mail at bbnitsc@nppd.com if you have any questions or comments concerning the questions.

Bob Nitsch
GGS Project Engineering Leader

lmh

Attachments

c: John Meacham

T:\MPCE\PROJECT FILES\01.13 S&L ENGINEERING SERVICES AGREEMENT 4700000926\01.13.10 SUBMITTAL FORMS TO S&L\#282 LETTER 110725 - COMMENTS ON S&L COST ESTIMATES.DOCX

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ATTACHMENT A

The following is a list of potential MPCE options that the District's Resource Planning and Risk Management group is trying to financially evaluate in light of potential emission regulations that have just been finalized or proposed to be implemented in the near future for the utility industry.

MPCE Options (GGS)

1) Scrubbers installed on both units under a single contract (most similar to current S&L estimate)
2) Scrubber installed on Unit #1
3) Scrubber installed on Unit #2
4) SCRs installed on both units under a single contract (most similar to current estimate)
5) SCR installed on Unit #1
6) SCR installed on Unit #2
7) DSI, or other bridging technology installed on a single unit
8) SNCR, or other bridging technology installed on a single unit

This group of District personnel is requesting assistance from appropriate Sargent & Lundy personnel in developing appropriate assumptions for each of these analysis options. The specific questions and information being requested by this group is noted in Attachments B and C of this letter.

ATTACHMENT B

The following set of questions were submitted to Bob Nitsch via a July 21, 2011 4:04 PM e-mail from Mr. Tim Owens, who works for the Resource Planning and Risk Management Group for the District. Mr. Owens comments and questions pertain to a spreadsheet document that was supplied by Wayshalee Patel via e-mail to Bob Nitsch on July 20, 2011 at 3:49 PM that pertained to the inputs used for the MPCE study.

Thanks for the information. I dug out my magnifying glass and took a look at the attached PDF file. With a couple of exceptions, I believe that the data in S&L's input sheets will provide the information we need for the Generation Options Analysis. Referring back to the NGOA Model template spreadsheet that I sent yesterday. Here is the list of what I think we are looking for:

- ***Earliest year available**: Operational Commercial Operation Date (year) – row 73 (for SO2 control) and row 88 (for NOx control)*
- ***Capital Cost**: rows 65 – 70 for (SO2 control) and rows 81 – 86 (for NOx control).*
  - *It would be helpful if there was a row that totaled up the six cost components for each option. Please see attached spreadsheet.*
  - *It isn't clear from the table whether the capital costs are referenced to a common year (say, 2011$) basis, the commercial operation date, or some other basis (mixed year $). Our preference would be to have all costs referenced to a common year (i.e., end-of-year 2011 $). Line 73 (for SO2 control) and Line 88 (for NOx control) defines the commercial operating date for each option. The capital costs have included items such as escalation and AFUDC to bring them to this commercial operating date. S&L is currently in the process of revising the wet FGD estimate to current day dollars and it will be available at the end of August. For the purposes of this request, we have used the costs listed in rows 65 – 70 for (SO2 control) and rows 81 – 86 (for NOx control) to evaluate Low/Base/High (10^{th}/ 50^{th}/ 90^{th}) estimates.*
  - *As we discussed, we would like to have Low/Base/High (10^{th}/ 50^{th}/ 90^{th}) estimates for the capital costs. Please see attached spreadsheet.*
- ***Fixed O&M Cost**: row 110 (for SO2 control) and row 114 (for NOx control).*
  - *It's not clear if row 120 (Annual Aux Power System Control Maintenance, Material, and Labor) should be included for each option as well, but I'm assuming so. It does appear that this cost was the same for all of the Scrubber & SCR options included in the PDF file. Annual Aux Power System Control Maintenance, Material, and Labor should be added to row 110 and row 114 for each option.*
  - *It isn't clear whether these costs are referenced to a common year (i.e., 2011$), or the commercial operation date. Our preference would be to*

have all the costs referenced to a common year (i.e., end-of-year 2011$). The fixed O&M cost shown is a first year cost with the base year being 2008 since that is when the pro forma was developed. The pro forma uses a 2.5% escalation rate from the first year cost to calculate the future years fixed O&M cost. See attached spreadsheet for 2011$.

- *Again, we would like to have Low/Base/High (10th/ 50th/ 90th) estimates for the FOM costs. Please see attached spreadsheet.*

- ***Variable O&M Cost**: Consumables/Products are listed in rows 124 to 146.*
  - *Rather than just having the quantities (tpy, gallons/year, etc.) listed, it would be very helpful if S&L could go through the process to calculate the VOM cost on a $/MWh basis. Our preference would be to have all costs referenced to a common year (i.e., end-of-year 2011 $/MWh) basis. See attached spreadsheet for VOM in 2011 and $/MWh.*
  - *I noticed that there are power (MW) impacts listed in this section (rows 130 – 133). As we mentioned yesterday, for purposes of the NGOA analysis, we do not want these impacts included in the VOM cost estimates, because we will be accounting for power impacts separately in our model. These have been deleted.*
  - *It appears that S&L has estimated the number of allowances bought or sold for each options. However, couldn't tell from the tables if any credits from the potential sale of allowances were included in the S&L pro forma analysis or not. Once again, we do not want any of these credits included in the VOM cost estimates. These have been deleted.*
  - *Finally, we would like to have Low/Base/High (10th/ 50th/ 90th) estimates for the VOM costs. Please see attached spreadsheet.*

- ***Capacity Impact**: Net Capacity (row 10) is listed for each unit. Additionally, power due to SO2 removal (row 130) and due to NOx removal (row 132) are also listed. I'm assuming that these values can be used to estimate the net unit capacity after the installation of a particular control option, correct? Yes, this is correct.*

- ***Existing average annual heat rate**: This appears to be listed in row 12.*

- ***Heat rate w/MPCE equipment**: Heat rate degradation is listed in row 145. However, all the values in the attached table appear to be zero. It doesn't make sense to me that one could operate this additional equipment and not have some impact on the associated heat rate, but perhaps I'm missing something. Would you please verify these assumptions with S&L? The intent of including a line item for heat rate degradation was to capture changes in heat rate due to normal operation, such as boiler fouling and normal wear and tear over time. This is already a part of the current operating cycle at NPPD so there should not be any additional degradation above and beyond normal operation. However, there would be a change in heat rate due to the additional auxiliary power associated* *with the new MPCE. The cost associated with this change in heat rate was taken into account via the auxiliary power cost. S&L understands that the heat rate will change due to the new MPCE equipment in the amount of the additional aux power, and is shown on the attached spreadsheets.*

- ***Outage length impact:*** *row 71 (for SO2 control) and row 87 (for NOx control).*

- ***SO2 emission rates w/ & w/o MPCE equipment:*** *uncontrolled & controlled rates (rows 22 & 23)*

- ***NOx emission rates w/ & w/o MPCE equipment:*** *uncontrolled & controlled rates (rows 46 & 47)*

- ***Hg emission rates w/ & w/o MPCE equipment:*** *Annual Hg emissions are listed (row 36), however, uncontrolled & controlled rates (rows 34 & 35) are not. Uncontrolled rate is 11.08 lb/TBtu (row 34) and Controlled rate is 1.11 lb/TBtu (row 35). Please ensure you are looking at the Hg options pro forma sheet and not the SO2 or NOx options pro forma sheets.*

- ***CO2 emission rates w/ & w/o MPCE equipment:*** *I don't see any information listed in the attached table for uncontrolled & controlled CO2 emission rates. S&L did not analyze the uncontrolled & controlled CO2 emission rates for the MPCE study.*

ATTACHMENT C

The following set of questions were gathered by Bob Nitsch during a July 20, 2011 meeting with personnel from the District's Resource Planning and Risk Management Group. The following questions pertain to the inputs used by Sargent and Lundy personnel for past MPCE study and cost estimation work. Note that some of these questions may be a repeat of the questions listed in Attachment B.

1. How did Sargent & Lundy set up and handle the SOx and NOx allowances and purchases in the previously performed pro-forma analysis? S&L did not include any NOx allowance purchase/sale since NPPD did not have allowances for this pollutant. However, the SO2 allowances were based on the following:

	SOX (tons)
Year	tons / unit
2005	16,600
2009	16,600
2010	14,977
2015	14,977
2018	14,977

GGS was allotted 16,600 allowances per Unit through 2009 and then it would go down to 14,977 allowances per Unit in 2010. One allowance would be surrendered for every 1 ton of SO2 emitted. Any allowances left over would be sold at an allowance price projection that was based on industry data from PACE Consulting. The initial price per ton of SO2 used in the model was $282/ton escalated at 5-6% per year until 2025, whereby the allowance price would remain the same for the rest of the years. These are dated allowance prices and allocations and should not be used moving forward. They have been removed from the variable O&M costs in the attached spreadsheets.

2. Did Sargent & Lundy utilize a bell curve or similar for the individual component costs in their cost estimating? S&L does not use a bell curve for individual component pricing. S&L uses actual prices based on current day indices (i.e. steel, rolled plate, etc.).

3. What is the delta heat rate penalty due to the addition of various potential MPCE? See attached spreadsheets for the net plant heat rate with the installation of the various MPCE equipment.

4. What is the heat rate impact on boiler efficiency if certain pieces of existing plant equipment are removed such as the Unit 2 precipitators and appurtenant economizer outlet duct? The effect of removal of the ESP's on boiler efficiency was not looked at during the MPCE study. NPPD sent a very detailed study (from 2001) that NPPD performed on the change in boiler efficiency with the demolition of the Unit 1 and Unit 2 ESPs. Per our weekly telecom, S&L will review this study and provide feedback within a week.

5. Need the CO_2 impact on all of these technologies? Please see attached spreadsheets that determine the CO2 emissions.

6. What costs savings would be realized if we did both FGDs or SCRs at the same time versus doing one at a time separated by an extended time period?

   - Contractor would mobilize/demobilize only one time.

   - Constructing one FGD would defer the cost of the other Units absorber, chimney, fans ductwork, foundation and steel; however all of the common systems (sized for both Units FGDs) would need to be installed with the first Units FGD, including reagent prep/handling, dewatering, rail upgrades etc.

   - Constructing one SCR would defer the cost of the other Units reactor, ductwork, catalyst, and economizer modifications; however like the common systems in the FGD, the SCR commons systems (sized for both Units SCRs) would need to be installed with the first Units SCR. Since the ammonia system is the main common component, it is only a small part of the overall cost and not as dramatic as for the FGD.

   - When FGDs or SCRs are done together there would be a small savings in engineering since they would be identical designs being done at the same time. However, installing one FGD now and the other FGD several years later could negate any savings, since they are not being done at the same time and it would be as if the contractor was starting from scratch.

   - Almost no capital cost savings in the auxiliary power upgrades if both Units were done at the same time v. separately.

   - When FGDs or SCRs are done at the same time, there will be some erection cost savings because after building the first unit, the crew moves over to the second unit and they are on a higher learning curve. Along with this, NPPD could attract labor more easily with a long term commitments in lieu of a shorter one if only one Unit was built.

- Constructing one FGD or one SCR would run the risk of the second FGD or SCR being from a different vendor, different warehouse spares, different equipment. On the other hand if you sole source the second Unit to the vendor who built the first Unit, NPPD could run the risk of paying a high premium.

Nebraska Public Power District
Gerald Gentleman Station

Summary of Capital Cost Range for MPCE Equipment

Project No. 12681-006
8/8/2011

For the 10/LOW case we set the ranges for each category in the cost estimates to min 90% to max 100% of the original cost. These ranges are then entered into a software program utilizing Monte Carlo Simulation. The Monte Carlo Simulation is based on running 10,000 iterations where the inputs are randomly generated from probability distribution curves to simulate the process of sampling. The output is a curve where a point on the curve gives % confidence factor and corresponding overall dollar amount for the project to meet that confidence factor.

For the 90/HIGH case, we set the ranges to min. 95% to max 150% (each category has a different high range based on our expectations for that category). These ranges are then entered into the same software program to run Monte Carlo Simulation to determine the 90/HIGH levels for each cost estimate. Again, the output is a curve where a point on the curve gives % confidence factor and corresponding overall dollar amount for the project to meet that confidence factor.

The 50/BASE case is the original total cost estimate for each technology.

Cost Estimate Description	10th/LOW	50th/BASE	90th/HIGH
WET FGD	$ 991,057,500	$ 1,035,079,000	$ 1,136,117,500
DRY FGD w/ Reinforcement	$ 1,016,470,100	$ 1,061,052,000	$ 1,163,583,900
SCR	$ 462,468,800	$ 483,411,000	$ 533,141,500
SNCR	$ 36,405,144	$ 38,230,644	$ 44,492,044
ACI	$ 8,634,145	$ 9,122,045	$ 11,215,845

Question 1

The table below shows the 10%, 50%(baseline), and 90% cases for fixed and variable O&M for the various cases studied. The 90% results (i.e., values with 90% confidence they will not be exceeded) generally are about 15% higher than the baseline values. The 10% results (10% confidence of coming in below this value) are typically 8% to 10% below the baseline. These results were calculated using the same spreadsheet model as for the original baseline calculations, but with a Monte Carlo add-in that allowed consideration of a range of possibilities regarding the cost and quantity inputs. The simulation was done using a triangular distribution function for inputs, specified as a low, most probable, and high value. The most probable values are those that were used in the baseline calculations. The high and low values for each variable were specified according to judgments as to the uncertainty of each variable.

	Status Quo Case 0.28% S, Unit 1	Status Quo Case 0.28% S, Unit 2	No Equipment Installed 0.7% S, Unit 1	No Equipment Installed 0.7% S, Unit 2	No Equipment Installed 1.0% S, Unit 1	No Equipment Installed 1.0% S, Unit 2	Wet FGD 0.28% Sulfur Fuel, Unit 1	Wet FGD 0.28% Sulfur Fuel, Unit 2	Dry FGD 0.28% Sulfur Fuel, Unit 1	Dry FGD 0.28% Sulfur Fuel, Unit 2
Case	1	2	3	4	5	6	7	8	9	10
Fixed O&M, $2011										
Baseline/50%	$0	$0	$0	$0	$0	$0	$4,140,100	$4,140,100	$3,079,900	$3,079,900
Low/10% case	$0	$0	$0	$0	$0	$0	$3,822,000	$3,824,700	$2,858,600	$2,860,100
High/90% case	$0	$0	$0	$0	$0	$0	$4,733,400	$4,735,500	$3,499,200	$3,503,300
Variable O&M, $2011/gross MWh										
Baseline/50%	$0.044	$0.042	$0.045	$0.043	$0.044	$0.043	$0.405	$0.391	$0.747	$0.718
Low/10% case	$0.040	$0.039	$0.042	$0.040	$0.041	$0.039	$0.405	$0.390	$0.734	$0.707
High/90% case	$0.052	$0.050	$0.053	$0.051	$0.053	$0.051	$0.459	$0.443	$0.858	$0.824

	Wet FGD 0.7% Sulfur Fuel, Unit 1	Wet FGD 0.7% Sulfur Fuel, Unit 2	Dry FGD 0.7% Sulfur Fuel, Unit 1	Dry FGD 0.7% Sulfur Fuel, Unit 2	Wet FGD 1.0% Sulfur Fuel, Unit 1	Wet FGD 1.0% Sulfur Fuel, Unit 2	Dry FGD 1.0% Sulfur Fuel, Unit 1	Dry FGD 1.0% Sulfur Fuel, Unit 2	Fuel Additive Unit 1
Case	11	12	13	14	15	16	17	18	19
Fixed O&M, $2011									
Baseline/50%	$4,140,100	$4,140,100	$3,079,900	$3,079,900	$4,140,100	$4,140,100	$3,079,900	$3,079,900	$50,900
Low/10% case	$3,824,600	$3,825,000	$2,858,500	$2,858,900	$3,825,100	$3,824,800	$2,857,700	$2,857,300	$45,500
High/90% case	$4,733,100	$4,735,800	$3,499,800	$3,501,400	$4,736,600	$4,731,100	$3,507,100	$3,499,400	$60,000
Variable O&M, $2011/gross MWh									
Baseline/50%	$0.706	$0.679	$1.481	$1.423	$0.872	$0.839	$2.086	$2.003	$0.177
Low/10% case	$0.700	$0.673	$1.442	$1.387	$0.861	$0.829	$2.022	$1.943	$0.175
High/90% case	$0.804	$0.776	$1.721	$1.653	$0.996	$0.959	$2.432	$2.335	$0.208

	Fuel Additive Unit 2	ACI Unit 1	ACI Unit 2	ACI 50% Landfill Unit 1	ACI 50% Landfill Unit 2	SCR Unit 1	SCR Unit 2	SNCR Unit 1	SNCR Unit 2
Case	20	21	22	23	24	25	26	27	28
Fixed O&M, $2011									
Baseline/50%	$50,900	$56,200	$56,200	$56,200	$56,200	$545,500	$545,500	$145,500	$145,500
Low/10% case	$45,500	$51,000	$51,000	$51,000	$50,900	$498,500	$497,300	$135,200	$135,200
High/90% case	$60,000	$65,800	$65,700	$65,700	$65,700	$635,300	$635,700	$166,100	$166,200
Variable O&M, $2011/gross MWh									
Baseline/50%	$0.166	$0.556	$0.558	$0.480	$0.485	$0.628	$0.602	$0.300	$0.286
Low/10% case	$0.167	$0.532	$0.534	$0.453	$0.450	$0.620	$0.596	$0.290	$0.278
High/90% case	$0.197	$0.655	$0.659	$0.574	$0.582	$0.718	$0.690	$0.351	$0.336

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Assumptions in CO2 Emissions Calculations

Project No. 12661-006
8/5/2011

The following assumptions were made in the CO2 emissions calculations:

1. The baseline 24-month heat input was calculated by taking the average of the highest 24-month period within the last five years (2006-2011).
2. The annual baseline heat input was calculated by taking the 24-month heat input and dividing by two.
3. Potential changes in boiler efficiency were not included in the calculation.
4. The calculations were performed based on no change in the net turbine heat rate.
5. The CO2 emissions from the process are based on the generation of CO2 from the chemical reactions of limestone in wet FGD, urea in SNCR and SCR and Trona in DSI.
6. The baseline annual CO2 emissions were calculated by taking the average of the highest 24-month period within the last five years (2006-2011) and dividing by two.
7. Auxiliary power requirements for the air pollution control systems were based on the values identified in the MPCE study for the various scenarios.
8. The methodology used to calculate potential CO2 emissions associated with the operation of the air pollution control systems represents a "worst-case" scenario, in that it assumes that heat input to the boiler could be increased to compensate for the increased parasitic load under all operating conditions. The methodology is intended to identify those air pollution control systems more likely to trigger New Source Review for GHG emissions.

Nebraska Public Power District
Gerald Gentleman Station

Summary of CO2 Emissions Impact from MPCE

Project No. 12681-006
8/5/2011

Scenario: Wet FGD 0.28% Sulfur Fuel, Unit 1

		Baseline	Projected	Change
Gross Plant Output:	kW-gross	705,000	705,000	0
Auxiliary Power Requirement:	kW	39,974	53,714	13,740
Net Plant Output:	kW-net	665,026	651,286	-13,740
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	81.60%	81.60%	0.00%
Auxiliary Power Requirement:	%	5.67%	7.62%	1.9%
Net Plant Heat Rate:	Btu/kWh-net	**11,017**	**11,249**	232
Maximum Hourly Heat Input:	mmBtu/hr	7,327	7,326	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**56,093,484**		
Baseline Annual Net Output:	kWh-net/yr	5,091,538,894	5,091,538,894	
Revised Annual Heat Input:	MMBtu/yr		57,274,721	
Increased Annual Heat Input:	MMBtu/yr		1,181,237	
		Baseline	Projected	Change
CO2 Emission Rate:	lb/MMBtu	205.6	205.6	
	tpy	5,766,410	5,887,841	121,431
CO2 Emissions from the Process	tpy			13,550
Total Change in CO2 Emissions:	tpy			134,981

Scenario: Wet FGD 0.28% Sulfur Fuel, Unit 2

		Baseline	Projected	Change
Gross Plant Output:	kW-gross	745,000	745,000	0
Auxiliary Power Requirement:	kW	44,998	58,738	13,740
Net Plant Output:	kW-net	700,002	686,262	-13,740
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	82.71%	82.71%	0.00%
Auxiliary Power Requirement:	%	6.04%	7.88%	1.8%
Net Plant Heat Rate:	Btu/kWh-net	**10,912**	**11,130**	218
Maximum Hourly Heat Input:	mmBtu/hr	7,638	7,638	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**58,614,791**		
Baseline Annual Net Output:	kWh-net/yr	5,371,590,084	5,371,590,084	
Revised Annual Heat Input:	MMBtu/yr		59,785,798	
Increased Annual Heat Input:	MMBtu/yr		1,171,007	
		Baseline	Projected	Change
CO2 Emission Rate:	lb/MMBtu	207.8	207.8	
	tpy	6,090,077	6,211,744	121,667
CO2 Emissions from the Process	tpy			13,530
Total Change in CO2 Emissions:	tpy			135,197

Scenario: Wet FGD 0.7% Sulfur Fuel, Unit 1

		Baseline	Projected	Change
Gross Plant Output:	kW-gross	705,000	705,000	0
Auxiliary Power Requirement:	kW	39,974	55,774	15,800
Net Plant Output:	kW-net	665,026	649,226	-15,800
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	81.60%	81.60%	0.00%
Auxiliary Power Requirement:	%	5.67%	7.91%	2.2%
Net Plant Heat Rate:	Btu/kWh-net	**11,017**	**11,285**	268
Maximum Hourly Heat Input:	mmBtu/hr	7,327	7,327	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**56,093,484**		
Baseline Annual Net Output:	kWh-net/yr	5,091,538,894	5,091,538,894	
Revised Annual Heat Input:	MMBtu/yr		57,458,016	
Increased Annual Heat Input:	MMBtu/yr		1,364,532	
		Baseline	Projected	Change
CO2 Emission Rate:	lb/MMBtu	205.6	205.6	
	tpy	5,766,410	5,906,684	140,274
CO2 Emissions from the Process	tpy			35,525
Total Change in CO2 Emissions:	tpy			175,799

Scenario: Wet FGD 0.7% Sulfur Fuel, Unit 2

		Baseline	Projected	Change
Gross Plant Output:	kW-gross	745,000	745,000	0
Auxiliary Power Requirement:	kW	44,998	60,798	15,800
Net Plant Output:	kW-net	700,002	684,202	-15,800
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	82.71%	82.71%	0.00%
Auxiliary Power Requirement:	%	6.04%	8.16%	2.1%
Net Plant Heat Rate:	Btu/kWh-net	**10,912**	**11,164**	252
Maximum Hourly Heat Input:	mmBtu/hr	7,638	7,638	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**58,614,791**		
Baseline Annual Net Output:	kWh-net/yr	5,371,590,084	5,371,590,084	
Revised Annual Heat Input:	MMBtu/yr		59,968,432	
Increased Annual Heat Input:	MMBtu/yr		1,353,641	
		Baseline	Projected	Change
CO2 Emission Rate:	lb/MMBtu	207.8	207.8	
	tpy	6,090,077	6,230,720	140,643
CO2 Emissions from the Process	tpy			35,978
Total Change in CO2 Emissions:	tpy			176,621

Scenario: Wet FGD 1.0% Sulfur Fuel, Unit 1

		Baseline	Projected	Change
Gross Plant Output:	kW-gross	705,000	705,000	0
Auxiliary Power Requirement:	kW	39,974	55,774	15,800
Net Plant Output:	kW-net	665,026	649,226	-15,800
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	81.60%	81.60%	0.00%
Auxiliary Power Requirement:	%	5.67%	7.91%	2.2%
Net Plant Heat Rate:	Btu/kWh-net	**11,017**	**11,285**	268
Maximum Hourly Heat Input:	mmBtu/hr	7,327	7,327	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**56,093,484**		
Baseline Annual Net Output:	kWh-net/yr	5,091,538,894	5,091,538,894	
Revised Annual Heat Input:	MMBtu/yr		57,458,016	
Increased Annual Heat Input:	MMBtu/yr		1,364,532	
		Baseline	Projected	Change
CO2 Emission Rate:	lb/MMBtu	205.6	205.6	
	tpy	5,766,410	5,906,684	140,274
CO2 Emissions from the Process	tpy			46,462
Total Change in CO2 Emissions:	tpy			186,736

Scenario: Dry FGD 1.0% Sulfur Fuel, Unit 2

		Baseline	Projected	Change
Gross Plant Output:	kW-gross	745,000	745,000	0
Auxiliary Power Requirement:	kW	44,998	60,798	15,800
Net Plant Output:	kW-net	700,002	684,202	-15,800
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	82.71%	82.71%	0.00%
Auxiliary Power Requirement:	%	6.04%	8.16%	2.1%
Net Plant Heat Rate:	Btu/kWh-net	**10,912**	**11,164**	252
Maximum Hourly Heat Input:	mmBtu/hr	7,638	7,638	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**58,614,791**		
Baseline Annual Net Output:	kWh-net/yr	5,371,590,084	5,371,590,084	
Revised Annual Heat Input:	MMBtu/yr		59,968,432	
Increased Annual Heat Input:	MMBtu/yr		1,353,641	
		Baseline	Projected	Change
CO2 Emission Rate:	lb/MMBtu	207.8	207.8	
	tpy	6,090,077	6,230,720	140,643
CO2 Emissions from the Process	tpy			47,124
Total Change in CO2 Emissions:	tpy			187,767

Nebraska Public Power District
Gerald Gentleman Station

Summary of CO_2 Emissions Impact from MPCE

Project No. 12681-006
8/5/2011

Scenario: Dry FGD 0.28% Sulfur Fuel, Unit 1				
		Baseline	Projected	Change
Gross Plant Output:	kW-gross	705,000	705,000	0
Auxiliary Power Requirement:	kW	39,974	49,774	9,800
Net Plant Output:	kW-net	665,026	655,226	-9,800
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	81.60%	81.60%	0.00%
Auxiliary Power Requirement:	%	5.67%	7.06%	1.4%
Net Plant Heat Rate:	Btu/kWh-net	**11,017**	**11,182**	165
Maximum Hourly Heat Input:	mmBtu/hr	7,327	7,327	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**56,093,484**		
Baseline Annual Net Output:	kWh-net/yr	5,091,538,894	5,091,538,894	
Revised Annual Heat Input:	MMBtu/yr		56,933,588	
Increased Annual Heat Input:	MMBtu/yr		840,104	
		Baseline	Projected	Change
CO_2 Emission Rate:	lb/MMBtu	205.6	205.6	
	tpy	5,766,410	5,852,773	86,363
CO_2 Emissions from the Process	tpy			0
Total Change in CO_2 Emissions:	tpy			86,363

Scenario: Dry FGD 0.28% Sulfur Fuel, Unit 2				
		Baseline	Projected	Change
Gross Plant Output:	kW-gross	745,000	745,000	0
Auxiliary Power Requirement:	kW	44,998	54,798	9,800
Net Plant Output:	kW-net	700,002	690,202	-9,800
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	82.71%	82.71%	0.00%
Auxiliary Power Requirement:	%	6.04%	7.36%	1.3%
Net Plant Heat Rate:	Btu/kWh-net	**10,912**	**11,067**	155
Maximum Hourly Heat Input:	mmBtu/hr	7,638	7,638	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**58,614,791**		
Baseline Annual Net Output:	kWh-net/yr	5,371,590,084	5,371,590,084	
Revised Annual Heat Input:	MMBtu/yr		59,447,387	
Increased Annual Heat Input:	MMBtu/yr		832,596	
		Baseline	Projected	Change
CO_2 Emission Rate:	lb/MMBtu	207.8	207.8	
	tpy	6,090,077	6,176,584	86,507
CO_2 Emissions from the Process	tpy			0
Total Change in CO_2 Emissions:	tpy			86,507

Scenario: Dry FGD 0.7% Sulfur Fuel, Unit 1				
		Baseline	Projected	Change
Gross Plant Output:	kW-gross	705,000	705,000	0
Auxiliary Power Requirement:	kW	39,974	50,604	10,630
Net Plant Output:	kW-net	665,026	654,396	-10,630
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	81.60%	81.60%	0.00%
Auxiliary Power Requirement:	%	5.67%	7.18%	1.5%
Net Plant Heat Rate:	Btu/kWh-net	**11,017**	**11,196**	179
Maximum Hourly Heat Input:	mmBtu/hr	7,327	7,327	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**56,093,484**		
Baseline Annual Net Output:	kWh-net/yr	5,091,538,894	5,091,538,894	
Revised Annual Heat Input:	MMBtu/yr		57,004,869	
Increased Annual Heat Input:	MMBtu/yr		911,385	
		Baseline	Projected	Change
CO_2 Emission Rate:	lb/MMBtu	205.6	205.6	
	tpy	5,766,410	5,860,101	93,691
CO_2 Emissions from the Process	tpy			0
Total Change in CO_2 Emissions:	tpy			93,691

Scenario: Dry FGD 0.7% Sulfur Fuel, Unit 2				
		Baseline	Projected	Change
Gross Plant Output:	kW-gross	745,000	745,000	0
Auxiliary Power Requirement:	kW	44,998	55,628	10,630
Net Plant Output:	kW-net	700,002	689,372	-10,630
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	82.71%	82.71%	0.00%
Auxiliary Power Requirement:	%	6.04%	7.47%	1.4%
Net Plant Heat Rate:	Btu/kWh-net	**10,912**	**11,080**	168
Maximum Hourly Heat Input:	mmBtu/hr	7,638	7,638	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**58,614,791**		
Baseline Annual Net Output:	kWh-net/yr	5,371,590,084	5,371,590,084	
Revised Annual Heat Input:	MMBtu/yr		59,517,218	
Increased Annual Heat Input:	MMBtu/yr		902,427	
		Baseline	Projected	Change
CO_2 Emission Rate:	lb/MMBtu	207.8	207.8	
	tpy	6,090,077	6,183,839	93,762
CO_2 Emissions from the Process	tpy			0
Total Change in CO_2 Emissions:	tpy			93,762

Scenario: Dry FGD 1.0% Sulfur Fuel, Unit 1				
		Baseline	Projected	Change
Gross Plant Output:	kW-gross	705,000	705,000	0
Auxiliary Power Requirement:	kW	39,974	50,604	10,630
Net Plant Output:	kW-net	665,026	654,396	-10,630
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	81.60%	81.60%	0.00%
Auxiliary Power Requirement:	%	5.67%	7.18%	1.5%
Net Plant Heat Rate:	Btu/kWh-net	**11,017**	**11,196**	179
Maximum Hourly Heat Input:	mmBtu/hr	7,327	7,327	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**56,093,484**		
Baseline Annual Net Output:	kWh-net/yr	5,091,538,894	5,091,538,894	
Revised Annual Heat Input:	MMBtu/yr		57,004,869	
Increased Annual Heat Input:	MMBtu/yr		911,385	
		Baseline	Projected	Change
CO_2 Emission Rate:	lb/MMBtu	205.6	205.6	
	tpy	5,766,410	5,860,101	93,691
CO_2 Emissions from the Process	tpy			0
Total Change in CO_2 Emissions:	tpy			93,691

Scenario: Dry FGD 1.0% Sulfur Fuel, Unit 2				
		Baseline	Projected	Change
Gross Plant Output:	kW-gross	745,000	745,000	0
Auxiliary Power Requirement:	kW	44,998	55,628	10,630
Net Plant Output:	kW-net	700,002	689,372	-10,630
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	82.71%	82.71%	0.00%
Auxiliary Power Requirement:	%	6.04%	7.47%	1.4%
Net Plant Heat Rate:	Btu/kWh-net	**10,912**	**11,080**	168
Maximum Hourly Heat Input:	mmBtu/hr	7,638	7,638	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**58,614,791**		
Baseline Annual Net Output:	kWh-net/yr	5,371,590,084	5,371,590,084	
Revised Annual Heat Input:	MMBtu/yr		59,517,218	
Increased Annual Heat Input:	MMBtu/yr		902,427	
		Baseline	Projected	Change
CO_2 Emission Rate:	lb/MMBtu	207.8	207.8	
	tpy	6,090,077	6,183,839	93,762
CO_2 Emissions from the Process	tpy			0
Total Change in CO_2 Emissions:	tpy			93,762

Nebraska Public Power District
Gerald Gentleman Station

Summary of CO2 Emissions Impact from MPCE

Project No. 12681-006
8/5/2011

Controls: SCR Unit 1				
		Baseline	Projected	Change
Gross Plant Output:	kW-gross	705,000	705,000	0
Auxiliary Power Requirement:	kW	39,974	44,974	5,000
Net Plant Output:	kW-net	665,026	660,026	-5,000
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	81.60%	81.60%	0.00%
Auxiliary Power Requirement:	%	5.67%	6.38%	0.7%
Net Plant Heat Rate:	Btu/kWh-net	**11,017**	**11,100**	83
Maximum Hourly Heat Input:	mmBtu/hr	7,327	7,326	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**56,093,484**		
Baseline Annual Net Output:	kWh-net/yr	5,091,538,894	5,091,538,894	
Revised Annual Heat Input:	MMBtu/yr		56,516,082	
Increased Annual Heat Input:	MMBtu/yr		422,598	
		Baseline	Projected	Change
CO2 Emission Rate:	lb/MMBtu	207.8	207.8	
	tpy	5,828,113	5,872,021	43,908
CO2 Emissions from the Process	tpy			3,123
Total Change in CO2 Emissions:	tpy			47,031

Controls: SCR Unit 2				
		Baseline	Projected	Change
Gross Plant Output:	kW-gross	745,000	745,000	0
Auxiliary Power Requirement:	kW	44,998	49,998	5,000
Net Plant Output:	kW-net	700,002	695,002	-5,000
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	82.71%	82.71%	0.00%
Auxiliary Power Requirement:	%	6.04%	6.71%	0.7%
Net Plant Heat Rate:	Btu/kWh-net	**10,912**	**10,990**	78
Maximum Hourly Heat Input:	mmBtu/hr	7,638	7,638	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**58,614,791**		
Baseline Annual Net Output:	kWh-net/yr	5,371,590,084	5,371,590,084	
Revised Annual Heat Input:	MMBtu/yr		59,033,775	
Increased Annual Heat Input:	MMBtu/yr		418,984	
		Baseline	Projected	Change
CO2 Emission Rate:	lb/MMBtu	205.2	205.2	
	tpy	6,013,878	6,056,865	42,987
CO2 Emissions from the Process	tpy			3,123
Total Change in CO2 Emissions:	tpy			46,110

Controls: SNCR Unit 1

		Baseline	Projected	Change
Gross Plant Output:	kW-gross	705,000	705,000	0
Auxiliary Power Requirement:	kW	39,974	40,474	500
Net Plant Output:	kW-net	665,026	664,526	-500
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	81.60%	81.60%	0.00%
Auxiliary Power Requirement:	%	5.67%	5.74%	0.1%
Net Plant Heat Rate:	Btu/kWh-net	**11,017**	**11,025**	8
Maximum Hourly Heat Input:	mmBtu/hr	7,327	7,326	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**56,093,484**		
Baseline Annual Net Output:	kWh-net/yr	5,091,538,894	5,091,538,894	
Revised Annual Heat Input:	MMBtu/yr		56,134,216	
Increased Annual Heat Input:	MMBtu/yr		40,732	
		Baseline	Projected	Change
CO2 Emission Rate:	lb/MMBtu	207.8	207.8	
	tpy	5,828,113	5,832,345	4,232
CO2 Emissions from the Process	tpy			2,824
Total Change in CO2 Emissions:	tpy			7,056

Controls: SNCR Unit 2

		Baseline	Projected	Change
Gross Plant Output:	kW-gross	745,000	745,000	0
Auxiliary Power Requirement:	kW	44,998	45,498	500
Net Plant Output:	kW-net	700,002	699,502	-500
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	82.71%	82.71%	0.00%
Auxiliary Power Requirement:	%	6.04%	6.11%	0.1%
Net Plant Heat Rate:	Btu/kWh-net	**10,912**	**10,920**	8
Maximum Hourly Heat Input:	mmBtu/hr	7,638	7,639	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**58,614,791**		
Baseline Annual Net Output:	kWh-net/yr	5,371,590,084	5,371,590,084	
Revised Annual Heat Input:	MMBtu/yr		58,657,764	
Increased Annual Heat Input:	MMBtu/yr		42,973	
		Baseline	Projected	Change
CO2 Emission Rate:	lb/MMBtu	205.2	205.2	
	tpy	6,013,878	6,018,287	4,409
CO2 Emissions from the Process	tpy			2,824
Total Change in CO2 Emissions:	tpy			7,233

Nebraska Public Power District
Gerald Gentleman Station

Summary of CO2 Emissions Impact from MPCE

Project No. 12681-006
8/5/2011

Controls: ACI Unit 1				
		Baseline	Projected	Change
Gross Plant Output:	kW-gross	705,000	705,000	0
Auxiliary Power Requirement:	kW	39,974	40,074	100
Net Plant Output:	kW-net	665,026	664,926	-100
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	81.60%	81.60%	0.00%
Auxiliary Power Requirement:	%	5.67%	5.68%	0.0%
Net Plant Heat Rate:	Btu/kWh-net	**11,017**	**11,018**	1
Maximum Hourly Heat Input:	mmBtu/hr	7,327	7,326	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**56,093,484**		
Baseline Annual Net Output:	kWh-net/yr	5,091,538,894	5,091,538,894	
Revised Annual Heat Input:	MMBtu/yr		56,098,576	
Increased Annual Heat Input:	MMBtu/yr		5,092	
		Baseline	Projected	Change
CO2 Emission Rate:	lb/MMBtu	207.8	207.8	
	tpy	5,828,113	5,828,642	529
CO2 Emissions from the Process	tpy			0
Total Change in CO2 Emissions:	tpy			529

Controls: ACI Unit 2				
		Baseline	Projected	Change
Gross Plant Output:	kW-gross	745,000	745,000	0
Auxiliary Power Requirement:	kW	44,998	45,098	100
Net Plant Output:	kW-net	700,002	699,902	-100
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	82.71%	82.71%	0.00%
Auxiliary Power Requirement:	%	6.04%	6.05%	0.0%
Net Plant Heat Rate:	Btu/kWh-net	**10,912**	**10,913**	1
Maximum Hourly Heat Input:	mmBtu/hr	7,638	7,638	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**58,614,791**		
Baseline Annual Net Output:	kWh-net/yr	5,371,590,084	5,371,590,084	
Revised Annual Heat Input:	MMBtu/yr		58,620,163	
Increased Annual Heat Input:	MMBtu/yr		5,372	
		Baseline	Projected	Change
CO2 Emission Rate:	lb/MMBtu	205.2	205.2	
	tpy	6,013,878	6,014,429	551
CO2 Emissions from the Process	tpy			0
Total Change in CO2 Emissions:	tpy			551

Nebraska Public Power District
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Summary of CO2 Emissions Impact from MPCE

Project No. 12681-006
8/5/2011

Controls: DSI Unit 1

		Baseline	Projected	Change
Gross Plant Output:	kW-gross	705,000	705,000	0
Auxiliary Power Requirement:	kW	39,974	43,774	3,800
Net Plant Output:	kW-net	665,026	661,226	-3,800
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	81.60%	81.60%	0.00%
Auxiliary Power Requirement:	%	5.67%	6.21%	0.5%
Net Plant Heat Rate:	Btu/kWh-net	**11,017**	**11,080**	63
Maximum Hourly Heat Input:	mmBtu/hr	7,327	7,326	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**56,093,484**		
Baseline Annual Net Output:	kWh-net/yr	5,091,538,894	5,091,538,894	
Revised Annual Heat Input:	MMBtu/yr		56,414,251	
Increased Annual Heat Input:	MMBtu/yr		320,767	
		Baseline	Projected	Change
CO2 Emission Rate:	lb/MMBtu	207.8	207.8	
	tpy	5,828,113	5,861,441	33,328
CO2 Emissions from the Process	tpy			31,883
Total Change in CO2 Emissions:	tpy			65,211

Controls: DSI Unit 2

		Baseline	Projected	Change
Gross Plant Output:	kW-gross	745,000	745,000	0
Auxiliary Power Requirement:	kW	44,998	48,798	3,800
Net Plant Output:	kW-net	700,002	696,202	-3,800
Net Turbine Heat Rate:	Btu/kWh	No Change	No Change	0
Boiler Efficiency:	%	82.71%	82.71%	0.00%
Auxiliary Power Requirement:	%	6.04%	6.55%	0.5%
Net Plant Heat Rate:	Btu/kWh-net	**10,912**	**10,971**	59
Maximum Hourly Heat Input:	mmBtu/hr	7,638	7,638	
		Baseline	Projected	
Baseline Annual Heat Input:	MMBtu/yr	**58,614,791**		
Baseline Annual Net Output:	kWh-net/yr	5,371,590,084	5,371,590,084	
Revised Annual Heat Input:	MMBtu/yr		58,931,715	
Increased Annual Heat Input:	MMBtu/yr		316,924	
		Baseline	Projected	Change
CO2 Emission Rate:	lb/MMBtu	205.2	205.2	
	tpy	6,013,878	6,046,394	32,516
CO2 Emissions from the Process	tpy			31,883
Total Change in CO2 Emissions:	tpy			64,399

Assumptions
Based on 0.75 lb/MMBtu SO2 inlet and 80% removal which requires approx. 38,000 lb/hr Trona injection per Unit.